Commonwealth of Kentucky
Division for Air Quality

PERMIT STATEMENT OF BASIS

DRAFT SYNTHETIC MINOR PERMIT NO. VF-02-001 (REVISION 1)
CATLETTSBURG REFINING, L.L.C.
CATLETTSBURG, KY
JUNE 19, 2003
GAURAV SHIL, REVIEWER
PLANT I.D. # 021-019-00004
APPLICATION LOG # 55330

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I. DESCRIPTION OF THE PROPOSED MODIFICATION

The site of the proposed project is the petroleum refinery operated by Catlettsburg Refining, LLC, a subsidiary of Marathon Ashland Petroleum LLC. This refinery is located on the Big Sandy River in Catlettsburg, Boyd County, Kentucky.

The refinery modernization project involves installation of new emissions units, modifications to some existing emissions units, and removal of some existing emissions units. This will allow the refinery to produce cleaner-burning transportation fuels, to improve yields, to utilize a wider range of purchased feed materials, and to reduce fixed and operating costs. In addition, the project will substantially reduce emissions of sulfur dioxide and nitrogen oxides from the refining operations.

PROPOSED CHANGES WITH LOG# 55330

This permit covers minor changes to the refinery modernization project scope that have occurred subsequent to the issuance of Synthetic minor construction permit number VF-02-001 on March 29, 2002, as well as changes to permit terms relating to monitoring requirements. As documented in permit number VF-02-001, the project will not result in a significant net emissions increase for any regulated air pollutant. Thus, the Prevention of Significant Deterioration (PSD) regulations codified at 401 KAR 51:017 and the major nonattainment area NSR regulations codified at 401 KAR 51:052 are not applicable. The proposed changes at the refinery include the following:

1. HYDROGEN GENERATION UNIT
A new process unit to be installed at the refinery is a Hydrogen Generation Unit (ID No. 2-122). The Hydrogen Generation Unit, its reformer vent, and the associated Reformer Heater (ID No. 2-122-B-1) are covered by the existing permit number VF-02-001. The existing permit number VF-02-001 is based on a nominal Hydrogen Generation Unit hydrogen production capacity of 30 million scf/day and a maximum allowable Reformer Heater heat input rate of 310 MMBtu/hr (lower heating value, LHV). The final, detailed engineering of the Hydrogen Generation Unit has resulted in two changes to the design of this unit: The nominal production capacity has increased to 34 million scf/day, and a dedicated emergency flare has been added. In addition, a dedicated cooling tower serving the Hydrogen Generation Unit has been added to the scope of the refinery modernization project. As a result of these changes, several permit terms are revised.

2. HF ALKY UNIT
The refinery modernization project scope has been expanded to include the addition of an HF Alky Hot Oil Heater (ID No. 2-36-B-2). This heater will be fired with natural gas and refinery fuel gas and will have a maximum heat input capacity of 18 MMBtu/hr (LHV). Permit terms allowing the installation of this heater are included in the revision.

3. DISTILLATE STORAGE TANKS
The refinery modernization project scope has been expanded to include the addition of four distillate storage tanks (Nos. 910, 911, 912, 913). Each tank will be equipped with an internal floating roof. Permit terms allowing the installation of these tanks are included in the revision.

4. CHANGES TO PERMIT TERMS

In addition to inclusion of new permit terms, existing permit terms for combustion devices, hydrotreaters, desulfurizers, storage vessels and Fluidized Catalytic Cracking Unit have been revised.
Section G a) 16, General Compliance Requirements has been removed with this revision.
General conditions for combustion devices, Specific monitoring requirement 2.D. has been deleted from VF-02-001 (Revision 1) because all combustion devices listed in Section B are not required to install NOx CEMS to demonstrate compliance with the synthetic minor NOx emission limits.
Pursuant to comments from Ashland Regional office, Operating Limitation 1.D.iii. for New Fluidized Catalytic Cracking Unit has been deleted.
The Division was processing the request related to requirement of CEMS and stack tests for various combustion devices. Pursuant to the request of the Permittee, in order to expedite the permitting process, the decision related to CEMS and stack test requirements is not made with this permitting step.

PROPOSED CHANGES WITH LOG# 53771

The only new process unit to be installed at the refinery is a Hydrogen Generation Unit (ID No. 2-122) with a nominal hydrogen production capacity of 30 million scf/day. The increased hydrogen supply is necessary for the increased hydrotreating capacity, which in turn is necessary for production of low-sulfur gasoline. The Hydrogen Generation Unit will include a fired Reformer Heater (ID No. 2-122-B-1).

One new storage vessel, Tank 920, will be installed. This tank will have a capacity of 150,000 barrels and will store gas oil.

The refinery process units to be modified are as follows:

The No. 2 Crude Unit (ID No. 1-2) will be modified to increase its nominal throughput capacity to 30,000 barrels per day. The existing heater within this unit (No. 2 Crude Charge Heater, ID No. 1-2-B-3) will not be modified.

The No. 3 Crude Unit (ID No. 2-23) will be modified to increase its crude slate flexibility, product recovery, and energy efficiency. The nominal capacity will be increased from 130,000 to 145,000 barrels per day. The heaters within this unit (No. 3 Crude Charge Heater #1, ID No. 2-23-B-3, and No. 3 Crude Charge Heater #2, ID No. 2-23-B-4) will be modified to increase heat input capacity, improve efficiency, and reduce NO_X emissions.

The No. 4 Vacuum Unit (ID No. 2-26) will be modified to increase its product recovery and energy efficiency and to increase its nominal capacity from 38,000 to 75,000 barrels per day. The existing heater within this unit (No. 4 Vacuum Charge Heater, ID No. 2-26-B-2) will not be modified. The existing FCC Charge Heater (currently ID No. 2-1-B-8) will be switched to the No. 4 Vacuum Unit and will operate in parallel with the existing No. 4 Vacuum Charge Heater and renamed as the No. 4 Vacuum Charge Heater (ID No. 2-23-B-6). This heater will be modified to increase its heat input capacity.

The existing Vacuum Gas Oil Hydrotreater (ID No. 2-104) will be modified to increase its nominal capacity from 40,000 to 60,000 barrels per day. This unit will be renamed the High-

Pressure Vacuum Gas Oil (HPVGO) Hydrotreater. The heaters within this unit (HPVGO Charge Heater No. 1, ID No. 2-104-B-1, and HPVGO Charge Heater No. 2, ID No. 2-104-B-2) will not be modified, but will be retrofitted with low-NO_X burners.

The existing Kerosene Desulfurizer (ID No. 2-103) will be converted to a gas oil hydrotreater with a nominal capacity of 40,000 barrels per day. This unit will be renamed the Low-Pressure Vacuum Gas Oil (LPVGO) Hydrotreater. The two reactor charge heaters within this unit (LPVGO Charge Heater No. 1, ID No. 2-103-B-1 and LPVGO Charge Heater No. 2, ID No. 2-103-B-2) will not be modified. The LPVGO Stripper Heater (ID 2-103-B-3) will be converted from a stripper reboiler to a stripper charge heater.

The existing Residual Catalytic Cracking (RCC) Unit (ID No. 2-109) will be expanded and converted to a Fluidized Catalytic Cracking (FCC) Unit with a nominal gas oil charge capacity of 95,000 barrels per day. Four condensing turbine drivers and the associated air blowers and wet gas compressors will be replaced with a single electric motor-driven air blower and a single electric motor-driven wet gas compressor to improve process flexibility and energy efficiency. The FCC Unit catalyst regenerator also will be modified and expanded.

The heat recovery units (Unit ID Nos. 2-116-B-1 and 2-116-B-2) associated with the converted FCC Unit will be retrofitted with low-NO_X burners, and one of the two units will be retrofitted with a selective non-catalytic reduction (SNCR) system. At each of these units, the internal grid will be removed and the steam turbines serving the forced-draft fans will be replaced with electric motors. The existing limestone scrubber serving the heat recovery units will be eliminated, as deep hydrotreating of FCC Unit feedstock will eliminate the need for further SO_2 control. (Provisions will be made to add a de-SO_x catalyst additive, should it be required, in order to meet the SO_2 emission limit.)

The Gas Concentration Plant (Unit ID No. 2-110) associated with the converted FCC Unit (ID No. 2-109) will be upgraded and expanded, including extensive piping modifications. This unit does not include any fired heaters.

The existing Distillate Desulfurizer (ID No. 2-121) will be modified to increase its nominal capacity from 55,000 to 75,000 barrels per day. The heaters within this unit (DDS Reactor Charge Heater No. 1, ID No. 2-121-B-1; DDS Reactor Charge Heater No. 2, ID No. 2-121-B-2; and DDS Stripper Reboiler, ID No. 2-121-B-3) will not be modified.

The existing Sulfur Recovery Plant (ID Nos. 2-106 and 2-120) will be modified to improve reliability and efficiency and to increase nominal capacity from 400 long tons per day to 600 long tons per day.

The No. 2 Vacuum Unit (ID No. 1-2), including the associated charge heater (ID No. 1-2-B-1), will be permanently removed from service.

The existing Fluidized Catalytic Cracking Unit (ID No. 2-1), including the associated CO boiler (ID No. 2-601-B-9) and electrostatic precipitator, will be permanently removed from service.

II. EMISSION ANALYSIS

A. Information Given and Assumed

All information used in making this determination was derived from the permit application and supplemental information provided by Catlettsburg Refining, L.L.C.

B. Emission Summaries and Calculation Methods

In accordance with KDAQ and U.S. EPA policy, the net emissions increase for each pollutant is calculated using the process set forth in the *New Source Review Workshop Manual*. The emissions increase calculations include emissions from new and modified emissions units as well as other affected emissions units upstream and downstream of the new and modified equipment. Emissions increases for all modified and debottlenecked emissions units are calculated using a past-actual-to-future-potential methodology.

For PM/PM_{10}, SO_2, NO_X, CO, and VOC emissions, netting analyses were performed, including all contemporaneous emissions increases and decreases. For all pollutants, the net emissions increases are less than significant (in fact, for PM/PM_{10}, SO_2, NO_X, and CO, the project will result in decreases).

Summary of Tables used for Emission Calculations

The emission calculations are summarized in the following tables. Specifically:

- Table 1 provides a listing of emission units affected by the proposed project and a summary of the emissions increase or decrease from each affected unit.

- Table 2 provides pre-modification actual emissions for the 24-month period June 1999 through May 2001 for each modified or debottlenecked emission unit.

- Table 3 provides post-modification potential emissions for each modified or debottlenecked emission unit. These values are equivalent to the permitted emission limits included in Section B of the draft permit.

- For each unit that is neither modified nor debottlenecked, Table 4 provides the incremental emissions increase.

- Table 5 provides the netting analyses, including all contemporaneous emissions increases and decreases.

Table 1. Summary of Emissions Changes

MAP Unit #	KEIS Unit #	Affected Units	emissions changes (tons/yr)					comments
			SO2	NOx	VOC	CO	PM10	
1-2	n/a	#2 Vacuum Unit			-6.4			Unit will be shut down. Emissions decreases represent baseline actual emissions.
1-2-B-1	B019	#2 Vacuum Charge Htr	-0.1	-5.5	-0.3	-4.6	-0.4	
1-2	n/a	#2 Crude Unit			0.1			Unit will undergo minor piping modifications. Emissions increases represent incremental change in component count.
1-2-B-3	B018	#2 Crude Charge Htr	-195.5	3.4	1.3	19.9	1.4	Heater may be debottlenecked. Emissions increases represent difference between maximum allowable emissions and 1999-2001 actual emissions.
2-1	n/a	(Old) FCC Unit			-78.4	-615.5		Unit will be shut down. (Charge heater is changing service and being moved to the #4 vacuum unit. For emissions increase purposes, this change is treated as a new installation - see below.) Emissions decreases represent baseline actual emissions.
2-1-B-8	B060	(Old) FCC Charge Htr	-0.5	-87.2	-1.7	-26.1	-2.4	
2-601-B-9	B017	(Old) FCC CO Boiler	-3,193.0	-387.0	-6.8	-160.9	-115.6	
2-2	n/a	(Old) FCC Gas Con Unit			-55.6			Equipment and components will be removed. Emissions decreases represent incremental change in component count.
2-23	n/a	#3 Crude Unit			9.9			Unit will undergo piping modifications. Emissions increases represent incremental change in component count.

Table 1. Summary of Emissions Changes								
			emissions changes (tons/yr)					
MAP Unit #	KEIS Unit #	Affected Units	SO2	NOx	VOC	CO	PM10	comments
2-23-B-3	B004	#3 Crude Unit Htr	19.6	-139.9	0.5	6.9	0.6	Heaters may be debottlenecked. Emissions increases represent difference between maximum allowable emissions and 1999-2001 actual emissions.
2-23-B-4	B005	#3 Crude Unit Htr	1.0	-136.3	0.5	8.0	0.7	
2-26		#4 Vacuum Unit			3.3			Unit will undergo piping modifications. Emissions increases represent incremental change in component count.
2-26-B-2		#4 Vacuum Charge Htr	11.6	7.9	0.6	9.4	0.8	Heater may be debottlenecked. Emissions increases represent difference between maximum allowable emissions and 1999-2001 actual emissions.
2-23-B-6		#4 Vacuum Charge Htr	21.4	111.3	4.4	66.8	6.0	Treated as a new emissions unit for calculation purposes - emissions increases represent maximum allowable emissions. (Was formerly the FCC charge heater and was treated as "shut down" in the FCC Unit - see above.)
2-30		Saturate gas plant						Unit may be debottlenecked. No change in piping or fugitive emissions.
2-30-B-1	B010	Saturate gas plant heater	20.1	-77.4	1.7	25.9	2.3	Heater ma be debottlenecked. Emissions increases represent difference between maximum allowable emissions (see “PTE” table for details) and baseline actual emissions (see “baseline” table for details)

Table 1. Summary of Emissions Changes								
			emissions changes (tons/yr)					
MAP Unit #	KEIS Unit #	Affected Units	SO2	NOx	VOC	CO	PM10	comments
2-36	n/a	HF Alky Unit						Unit may be debottlenecked. No change in piping or fugitive emissions.
2-36-B-1	B065	HF Alky Isostripper Reboiler	10.8	25.7	1.3	20.1	1.8	Heater may be debottlenecked. Emissions increases represent difference between maximum allowable emissions and 1999-2001 actual emissions.
2-122	n/a	Hydrogen Generation Unit			14.5			New installation. Includes reformer vent. No equipment in VOC service.
2-122-B-1	n/a	Reformer Heater	1.1	104.6	9.7	70.3	13.3	New installation. Emissions increases represent proposed maximum allowable emissions.
2-103	n/a	Low Pressure VGO Hydrotreater			14.1			Unit will undergo piping modifications. Emissions increases represent incremental change in component count.
2-103-B-1	B043	LPVGO Hydrotreater Charge Htr	5.4	19.6	1.1	16.3	1.5	Heaters may be debottlenecked. Emissions increases represent difference between maximum allowable emissions and 1999-2001 actual emissions.
2-103-B-2	B044	LPVGO Hydrotreater Charge Htr	2.0	4.5	0.1	2.2	0.2	
2-103-B-3	B045	LPVGO Hydrotreater Stripper Htr	4.7	16.2	0.8	12.9	1.2	
2-104	n/a	High Pressure VGO Hydrotreater			89.3			Unit will undergo piping modifications. Emissions increases represent incremental change in component count.
2-104-B-1	B046	HPVGO Hydrotreater Charge Htr	6.5	-36.5	0.9	13.7	1.2	Heaters may be debottlenecked. Emissions increases represent difference between maximum allowable emissions and 1999-2001 actual emissions.

Table 1. Summary of Emissions Changes								
			emissions changes (tons/yr)					
MAP Unit #	KEIS Unit #	Affected Units	SO2	NOx	VOC	CO	PM10	comments
2-104-B-2	B047	HPVGO Hydrotreater Charge Htr	6.2	-46.5	0.8	12.2	1.1	
2-106-B-307	B042	No. 1 SRU Thermal Oxidizer	144.2	7.9	0.4	6.6	0.6	Units may be debottlenecked by hydrotreater installations. Emissions increases represent difference between maximum allowable emissions and 1999-2001 actual emissions.
2-120-B-2	n/a	No. 2 SRU Thermal Oxidizer	147.9	9.4	0.5	7.9	0.7	
2-106 & 2-107	n/a	#1 Sulfur Plant						No change in component count.
2-118, 2-119 & 2-120	n/a	#2 Sulfur Plant						
2-109	n/a	(New) FCC Unit			8.6			Unit will undergo extensive piping modifications. Emissions increases represent incremental change in component count.
2-116-B-1, 2-116-B-2	B066, B067	(New) FCCU Heat Recovery Units North and South	-793.0	-261.0	38.2	415.9	46.0	Unit will undergo extensive modifications. Emissions increases represent difference between maximum allowable emissions and 1999-2001 actual emissions.
2-110	n/a	(New) FCC Gas Con Unit			16.0			Unit will undergo extensive piping modifications. Emissions increases represent incremental change in component count.
2-121	n/a	Distillate desulfurizer #2			4.4			Unit will undergo piping modifications. Emissions increases represent incremental change in component count.

Table 1. Summary of Emissions Changes								
			emissions changes (tons/yr)					
MAP Unit #	KEIS Unit #	Affected Units	SO2	NOx	VOC	CO	PM10	comments
2-121-B-1	B066	DD #2 Reactor Charge Htr	6.9	6.9	0.9	13.3	1.2	Heaters may be debottlenecked. Emissions increases represent difference between maximum allowable emissions and 1999-2001 actual emissions.
2-121-B-2	B067	DD #2 Reactor Charge Htr	6.9	7.3	0.9	13.3	1.2	
2-121-B-3	B068	DD #2 Stripper Reboiler	10.3	-86.4	0.2	2.8	0.3	
		Hydrogen plant cooling tower					0.4	New installation. Emissions increases represent proposed maximum allowable emissions.
		Hydrogen plant emergency flare		0.1	0.3	0.8		New installation. Emissions increases represent proposed maximum allowable emissions.
n/a	n/a	tankage			9.1			
Tank 701	HJ	gas oil			0.0			Tanks may be debottlenecked. Emissions increases represent difference between maximum allowable emissions and 1999-2001 actual emissions.
Tank 702	HK	gas oil			0.0			
Tank 845	LX	gas oil			0.0			
Tank 821	LH	gas oil			0.0			
Tank 733	IF	gas oil			4.6			
Tank 855	ME	gas oil			3.0			
Tank 81		gas oil			9.2			
Tank 152	FD	gas oil			0.0			
Tank 734	IM	FCC gasoline			1.9			
Tank 783	JT	FCC gasoline			2.9			

Table 1. Summary of Emissions Changes								
			emissions changes (tons/yr)					
MAP Unit #	KEIS Unit #	Affected Units	SO2	NOx	VOC	CO	PM10	comments
Tank 856	JV	FCC gasoline			0.9			
Tank 910		Distillate			1.2			
Tank 911		Distillate			0.6			
Tank 912		Distillate			0.6			
Tank 913		Distillate			1.0			
Tank 920	n/a	swing tank			10.1			
1-4-B-1	B021	P-Chem Reformer Guard Case Htr	0.9	2.9	0.2	2.7	0.2	
1-4-B-2,3,4	B022	P-Chem Reformer Htr	2.4	8.1	0.5	7.6	0.7	
1-4-B-7,8	B050	Petrochem Reformer Htr	1.1	3.5	0.2	3.3	0.3	
1-44-B-1		LP CCR Charge Heater	0.9	2.9	0.2	2.8	0.2	
1-44-B-2		LP CCR No. 1 Interheater	1.1	3.8	0.2	3.5	0.3	
1-44-B-3		LP CCR No. 2 Interheater	0.9	2.9	0.2	2.8	0.2	
1-44-B-4		LP CCR No. 3 Interheater	0.6	2.1	0.1	2.0	0.2	
1-44-B-5		LP CCR Debutanizer Reboiler	0.3	1.0	0.1	1.0	0.1	Emissions increases represent the incremental increases due to higher throughput/utilization.
2-35-B-1, 2	B040	C5/C6 Isomerization Heaters	1.0	3.2	0.2	3.0	0.3	
2-101-B-1	B064A	Naphtha Hydrotreater Charge Heater	0.8	2.5	0.2	2.4	0.2	
2-101-B-2	B064B	Naphtha Hydrotreater Stripper Reboiler	1.0	3.3	0.2	3.1	0.3	
2-102-B-1A	B109	HP CCR Reactor Heater	1.8	6.1	0.4	5.7	0.5	
2-102-B-1B	B110	HP CCR Reactor Heater	2.0	6.5	0.4	6.1	0.6	
2-102-B-1C	B111	HP CCR Reactor Heater	1.4	4.7	0.3	4.4	0.4	
2-102-B-1D	B112	HP CCR Reactor Heater	0.4	1.5	0.1	1.4	0.1	
2-102-B-2	B113	HP CCR Debutanizer Reboiler	0.3	1.1	0.1	1.0	0.1	

Table 1. Summary of Emissions Changes								
			emissions changes (tons/yr)					
MAP Unit #	KEIS Unit #	Affected Units	SO2	NOx	VOC	CO	PM10	comments
		Total project increases (not including decreases)	445.4	302.2	281.1	783.8	85.9	
		Significant level	40.0	40.0	40.0	100.0	15.0	
		Project significant / requires netting	yes	yes	yes	yes	yes	

Table 2. Baseline Actual Emissions

Affected Units	actual emissions (tons/yr) SO2	Nox	VOC	CO	PM10	Comments
#2 Vacuum Unit			6.4			Emissions represent equipment leaks.
#2 Vacuum Charge Htr	0.1	5.5	0.3	4.6	0.4	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
#2 Crude Charge Htr	208.3	44.3	1.3	20.2	2.2	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
(Old) FCC Unit			78.4	615.5		VOC emissions represent equipment leaks, including gas con unit. CO emissions represent periods of CO boiler bypass.
(Old) FCC Charge Htr	0.5	87.2	1.7	26.1	2.4	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
(Old) FCC CO Boiler	3,193.0	387.0	6.8	160.9	115.6	Emissions represent 6/1999 - 5/2001 actual emissions, based on CEMS data where available.
(Old) FCC Gas Con Unit			55.6			VOC emissions represent equipment leaks.
#3 Crude Unit Htr	1.2	194.2	3.8	58.3	5.3	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
#3 Crude Unit Htr	19.8	190.6	3.7	57.2	5.2	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
#4 Vacuum Charge Htr	4.6	34.8	2.7	41.2	3.7	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
#4 Vacuum Charge Htr						Zero "baseline" emissions in this service. (6/1999 - 5/2001 actual emissions represented for service as the FCC charge heater - see above.)
HF Alky Isostripper Reboiler	0.3	15.7	1.0	14.7	1.3	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.

Table 2. Baseline Actual Emissions

Affected Units	actual emissions (tons/yr) SO2	Nox	VOC	CO	PM10	Comments
LPVGO Hydrotreater Charge Htr	0.5	2.1	0.1	1.9	0.2	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
LPVGO Hydrotreater Charge Htr	3.9	17.1	1.0	16.0	1.4	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
LPVGO Hydrotreater Stripper Htr	1.8	7.9	0.5	7.3	0.7	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
HPVGO Hydrotreater Charge Htr	5.1	56.0	1.5	22.7	2.1	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
HPVGO Hydrotreater Charge Htr	5.5	66.0	1.6	24.2	2.2	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
No. 1 SRU Thermal Oxidizer	17.3	4.7	0.3	3.9	0.4	Actual emissions for 1999-2001. SO2 based on CEMS data; others based on fuel gas input and emission factors from AP-42 Section 1.4.
No. 2 SRU Thermal Oxidizer	13.6	3.2	0.2	2.7	0.2	Actual emissions for 1999-2001. SO2 based on CEMS data; others based on fuel gas input and emission factors from AP-42 Section 1.4.
(New) FCCU Heat Recovery Units North and South	1,049.0	498.0	16.8	32.1	219.3	Emissions represent 1999 - 2000 actual emissions.
DD #2 Reactor Charge Htr	0.2	4.7	0.6	8.9	0.8	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
DD #2 Reactor Charge Htr	0.2	4.2	0.6	8.9	0.8	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
DD #2 Stripper Reboiler	0.7	104.2	2.1	31.6	2.9	Emissions represent 6/1999 - 5/2001 actual emissions from fuel combustion.
gas oil						Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.

Table 2. Baseline Actual Emissions

Affected Units	actual emissions (tons/yr)					Comments
	SO2	Nox	VOC	CO	PM10	
gas oil						Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.
gas oil						Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.
gas oil						Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.
gas oil			0.2			Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.
gas oil			1.8			Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.
gas oil			0.1			Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.
gas oil						Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.
FCC gasoline			3.7			Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.
FCC gasoline			6.7			Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.
FCC gasoline			3.2			Emissions represent 6/1999 - 5/2001 actual emissions from standing and working losses.
swing tank						New tank – no baseline emissions.
Distillate						
Distillate						
Distillate						
Distillate						

Table 3. Potential Emissions

MAP Unit #	KEIS Unit #	Affected Units	maximum emissions (tons/yr)					Comments
			SO2	NOx	VOC	CO	PM10	
1-2-B-3	B018	#2 Crude Charge Htr	12.8	47.7	2.6	40.1	3.6	Maximum allowable emissions from fuel combustion assuming constant operation at maximum heat input capacity. Gas firing only.
2-23-B-3	B004	#3 Crude Unit Htr	20.8	54.3	4.3	65.2	5.9	Maximum allowable emissions from fuel combustion assuming constant operation at maximum heat input capacity. Gas firing only.
2-23-B-4	B005	#3 Crude Unit Htr	20.8	54.3	4.3	65.2	5.9	
2-26-B-2		#4 Vacuum Charge Htr	16.2	42.8	3.3	50.6	4.6	Maximum allowable emissions from fuel combustion assuming constant operation at maximum heat input capacity. Gas firing only.
2-23-B-6		#4 Vacuum Charge Htr	21.4	111.3	4.4	66.8	6.0	
2-30-B-1	B010	Saturate Gas Plant Heater	21.0	54.6	4.3	65.6	5.9	Heater may be debottlenecked. Emissions increases represent difference between maximum allowable emissions and baseline actual emissions.
2-36-B-1	B065	HF Alky Isostripper Reboiler	11.1	41.4	2.3	34.8	3.1	Maximum allowable emissions from fuel combustion assuming constant operation at maximum heat input capacity. Gas firing only.
2-36-B-2		HF Alky Hot Oil Heater	2.3	8.7	0.5	7.3	0.7	Maximum allowable emissions from fuel combustion assuming constant operation at maximum heat input capacity. Gas firing only.

Table 3. Potential Emissions

MAP Unit #	KEIS Unit #	Affected Units	maximum emissions (tons/yr)					Comments
			SO2	NOx	VOC	CO	PM10	
2-122	n/a	Hydrogen Generation Unit			14.5	4.6		VOC and CO from reformer vent. No components in VOC service.
2-122-B-1	n/a	Reformer Heater	1.1	104.6	9.7	70.3	13.3	Proposed maximum allowable emissions.
2-103-B-1	B043	LPVGO Hydrotreater Charge Htr	5.8	21.7	1.2	18.2	1.6	Maximum allowable emissions from fuel combustion assuming constant operation at maximum heat input capacity. Gas firing only.
2-103-B-2	B044	LPVGO Hydrotreater Charge Htr	5.8	21.7	1.2	18.2	1.6	
2-103-B-3	B045	LPVGO Hydrotreater Stripper Htr	6.5	24.1	1.3	20.2	1.8	
2-104-B-1	B046	HPVGO Hydrotreater Charge Htr	11.7	19.5	2.4	36.4	3.3	Maximum allowable emissions from fuel combustion assuming constant operation at maximum heat input capacity. Gas firing only.
2-104-B-2	B047	HPVGO Hydrotreater Charge Htr	11.7	19.5	2.4	36.4	3.3	
2-106-B-307	B042	No. 1 SRU Thermal Oxidizer	323.0	25.0	1.4	21.0	2.0	Maximum allowable emission rates. (Total for two emission points).
2-120-B-2	n/a	No. 2 SRU Thermal Oxidizer						
2-116-B-1, 2-116-B-2	B066, B067	(New) FCCU Heat Recovery Units North and South	256.0	237.0	55.0	448	265.4	Emissions represent proposed maximum allowable emissions, assuming constant operation at maximum coke burn rate.
2-121-B-1	B066	DD #2 Reactor Charge Htr	7.1	11.5	1.5	22.3	2.0	Maximum allowable emissions from fuel combustion assuming constant operation at maximum heat input capacity. Gas firing only.
2-121-B-2	B067	DD #2 Reactor Charge Htr	7.1	11.5	1.5	22.3	2.0	
2-121-B-3	B068	DD #2 Stripper Reboiler	11.0	17.8	2.3	34.4	3.1	

Table 3. Potential Emissions

MAP Unit #	KEIS Unit #	Affected Units	maximum emissions (tons/yr) SO2	NOx	VOC	CO	PM10	Comments
		H2 Plant Cooling Tower					0.4	Potential to emit based on 1000 gpm circulating water flow rate, 0.003% maximum liquid drift, 6000 ppmw total solids in circulating water.
		H2 Plant Emergency Flare		0.1	0.3	0.8		Potential to emit based on natural gas (pilot gas & purge gas) flow rate and emission factors from AP-42 Table 13.5-1
Tank 701	HJ	gas oil			51.89			Represents proposed maximum allowable emissions from tank throughput (working) and standing losses.
Tank 702	HK	gas oil						
Tank 845	LX	gas oil						
Tank 821	LH	gas oil						
Tank 733	IF	gas oil						
Tank 855	ME	gas oil						
Tank 81		gas oil						
Tank 152	FD	gas oil						
Tank 734	IM	FCC gasoline						
Tank 783	JT	FCC gasoline						
Tank 856	JV	FCC gasoline						

Table 3. Potential Emissions

MAP Unit #	KEIS Unit #	Affected Units	maximum emissions (tons/yr)					Comments
			SO2	NOx	VOC	CO	PM10	
Tank 910	n/a	distillate						
Tank 911	n/a	distillate						
Tank 912	n/a	distillate						
Tank 913	n/a	distillate						
Tank 920	n/a	swing tank						

Table 4. Incremental Emissions Increases								
MAP Unit #	KEIS Unit #	Affected Units	emissions changes (tons/yr)					Changes
			SO2	Nox	VOC	CO	PM10	
1-2	n/a	#2 Crude Unit			0.1			reflects change in component count
2-2	n/a	(Old) FCC Gas Con Unit			-55.6			reflects change in component count
2-23	n/a	#3 Crude Unit			9.9			reflects change in component count
2-26	n/a	#4 Vacuum Unit			3.3			reflects change in component count
2-103	n/a	Low Pressure VGO Hydrotreater			14.1			reflects change in component count
2-104	n/a	High Pressure VGO Hydrotreater			89.3			reflects change in component count
2-109	n/a	(New) FCC Unit			8.6			reflects change in component count
2-110	n/a	(New) FCC Gas Con Unit			16.0			reflects change in component count
2-121	n/a	Distillate desulfurizer #2			4.4			reflects change in component count
n/a	n/a	Tankage			17.4			reflects change in component count
Tank 910	n/a							
Tank 911	n/a							
Tank 912	n/a							
Tank 913	n/a							
1-4-B-1	B021	P-Chem Reformer Guard Case Htr	0.9	2.9	0.2	2.7	0.2	Incremental emissions increases based upon increase in actual fired duty equal to 10.7 percent of capacity.

1-4-B-2, 3,4	B022	P-Chem Reformer Htr	2.4	8.1	0.5	7.6	0.7	
1-4-B-7, 8	B050	Petrochem Reformer Htr	1.1	3.5	0.2	3.3	0.3	
1-44-B-1		LP CCR Charge Heater	0.9	2.9	0.2	2.8	0.2	
1-44-B-2		LP CCR No. 1 Interheater	1.1	3.8	0.2	3.5	0.3	
1-44-B-3		LP CCR No. 2 Interheater	0.9	2.9	0.2	2.8	0.2	
1-44-B-4		LP CCR No. 3 Interheater	0.6	2.1	0.1	2.0	0.2	
1-44-B-5		LP CCR Debutanizer Reboiler	0.3	1.0	0.1	1.0	0.1	
2-35-B-1, 2	B040	C5/C6 Isomerization Heaters	1.0	3.2	0.2	3.0	0.3	Incremental emissions increase based upon increase in actual fired duty equal to 8.1 percent of capacity.
2-101-B-1	B064A	Naphtha Hydrotreater Charge Heater	0.8	2.5	0.2	2.4	0.2	
2-101-B-2	B064B	Naphtha Hydrotreater Stripper Reboiler	1.0	3.3	0.2	3.1	0.3	
2-102-B-1A	B109	HP CCR Reactor Heater	1.8	6.1	0.4	5.7	0.5	
2-102-B-1B	B110	HP CCR Reactor Heater	2.0	6.5	0.4	6.1	0.6	
2-102-B-1C	B111	HP CCR Reactor Heater	1.4	4.7	0.3	4.4	0.4	
2-102-B-1D	B112	HP CCR Reactor Heater	0.4	1.5	0.1	1.4	0.1	
2-102-B-2	B113	HP CCR Debutanizer Reboiler	0.3	1.1	0.1	1.0	0.1	Incremental emissions increases based upon increase in actual fired duty equal to 10.7 percent of capacity.

Table 5. Netting Analyses

project	Comments	emissions changes (tons/yr) SO2	NOx	VOC	CO	PM10
note:	**assume nonattainment NSR contemporaneous period begins 7/1/1992**					
Refinery modernization project increases	See worksheet “summary”	445.36	302.22	281.15	783.81	85.85
Refinery modernization project decreases	See worksheet “summary”	-4,182.12	-1,263.61	-149.18	-807.12	-118.41
C-92-139 RCC Flare Tip Replacement	Placed in service sometime between 10/30/1992 (inspection) and 2/2/1993 (operating permit application). 10/1993 permit application not available. "No net emissions increase" based on 8/12/1992 and 10/22/1992 letters to DAQ.					
C-90-008 a) Tanks 868, 869 & b) CTLO exchanger	Taken from 1992 Netting Spreadsheet			4.72		
C-90-078 Amendment 1 (6 Projects in One)	Taken from 1992 Netting Spreadsheet			11.63		
C-90-147 FCC ESP amendment 2	Operation commenced between 2/10/1992 (inspection - construction underway) and 8/25/1992 (stack testing). Assumed no change in emission rate - no credit was taken for reducing PM emissions.					
C-90-171 No. 12 Boiler amendment 1	Taken from 1992 Netting Spreadsheet CTPMLIST.WK1	22.00	118.20	0.24	32.80	4.10
C-91-051 Distillate desulfurizer & cooling tower	Commenced operation 7/29/1993 through 8/11/1993 (individual emission units, based on 8/5/1993 and 8/19/1993 letters to DAQ). Revised construction permit issued 11/23/1993 reflects only administrative revisions, no modifications. Emissions increases based on 3/22/1991 and 8/22/1991 construction permit applications.	37.64	40.00	36.23	35.77	5.11
C-91-057 Spec G-Oil Treater (revision 2)	Commenced operation date not available; commenced construction date 3/5/1992 (based on 3/6/1992 letter to DAQ). Emissions increase based on 1/15/1992 application for revision to construction permit.			0.55		
C-91-075 Tanks 873, 874, 875	Reflects PTE of three new tanks and PTE-actual for six tanks undergoing a change in service			-30.67		
C-91-135 Benzene NESHAP WWTP	Commence operation date 1/28/1994 (based on 2/10/1994 letter to DAQ). Emissions changes based on 1999 KEIS pg 706/708 of 720 - Column marked "Total POTENTIAL Emissions."			18.13		

Table 5. Netting Analyses

project	Comments	emissions changes (tons/yr)				
		SO2	NOx	VOC	CO	PM10
C-91-136 Air Assisted Flare	Taken from 1999 KEIS pg 568 of 720 - Column marked "Total POTENTIAL Emissions"	0.13	0.61	0.01	0.15	0.01
C-92-017 DNO Loading Relocation	Commenced operation 8/12/1992 (based on 8/27/1992 letter to DAQ). VOC emissions increase based on 6/8/1992 construction permit application (revised). No credit taken for any VOC emissions decrease resulting from cessation of DNO loading at Old Naphtha Loading Rack.			5.83		
C-91-164 Tanks 48, 49, 55, 56	Commence operation date 12/7/1993. Emissions increase based on 5/21/1992 letter to DAQ (requesting revision to construction permit). Increase includes PTE of 3 new tanks, fugitive components associated with all 7 tanks covered by construction permit, and 2-year actual emissions of 14 tanks (14, 18, 24, 42, 62, 63, 66, 67, 68, 101, 102, 136, 137, 164) being removed concurrently.			-1.73		
C-91-164 Tanks 34, 43	Commence operation date 10/28/1994 (based on 11/2/1994 letter to DAQ). Emissions increase based on 5/21/1992 letter to DAQ (requesting revision to construction permit). Increase includes PTE of 2 new tanks only.			0.36		
C-91-164 Tanks 32	Commence operation date 7/29/1995 (based on 7/31/1995 letter to DAQ). Emissions increase based on 5/21/1992 letter to DAQ (requesting revision to construction permit). Increase includes PTE of new tank only.			4.61		
C-92-029 Tank 883	Commenced operation 12/21/1992 (based on 12/28/1992 letter to DAQ). Emissions increase based on 5/20/1991 construction permit application, reflects PTE of new tank and 2-year actual emissions of Tank 787 (being replaced).			-3.06		
C-91-175 Tank 884	Commenced operation 12/21/1992 (based on 12/28/1992 letter to DAQ). Emissions increase includes PTE of new tank and 2- year actual emissions of Tank 788 (being replaced).			-6.38		
n/a (1992) retrofit #4 boiler with low-NOx burners	Commence operation date not available, but ~ 11/5/1992 (submittal date for construction permit application for fired		-738.00			

Table 5. Netting Analyses

project	Comments	emissions changes (tons/yr)				
		SO2	NOx	VOC	CO	PM10
	duty increase at #5 crude charge heater, at which time installation was complete but unit was not yet operational)					
C-92-009 Additive Tank 891	Commence operation date not available (construction permit issued 2/21/1992). Emissions increase based on 12/18/1991 construction permit application.			1.18		
C-92-033 Petrochem CCR Unit	1-44-B-1 through B-4 heaters commenced operation on 9/28/1993 and B-5 heater on 10/6/1993 (based on 10/8/1993 letter to DAQ). CCR Unit (fugitives) commenced operation on 9/17/1993 (based on 9/20/1993 letter to DAQ). Emissions increases based on revised construction permit issued 10/11/1993 (except for CO - no limits in permit - based on KEIS) (initial permit issued 2/26/1992 was superseded). No credit taken for shutting down fixed-bed reformer (VOC emissions) or heater 1-4-B-1.	32.15				
C-92-033 Petrochem CCR Unit	Commenced operation on construction permit issuance date. Emissions increases based on 8/22/1995 revised construction permit and 10/26/1994 application (construction permit issued 2/26/1992 was superseded).	7.76				
C-92-062 Petrochem and South Area flare	Commence operation 1/11/1995 (based on 1/20/1995 letter to DAQ). Commenced construction 2/1/1993 (based on 2/10/1993 letter to DAQ). (Modification involved tie-in of several relief vents over ~2-year period.) Zero emissions increase, based on 1/27/1988 permit application.					
C-92-096 Furfural slop tanks 104, 882	Commenced operation 1/12/1994 (based on 1/17/1994 letter to DAQ). Emissions increases based on 5/6/1992 construction permit application.			5.95		
C-92-132 RCCS Ram Oil System	Operation commencement date not available; construction permit issued 9/29/1992. VOC emissions increase based on 2/21/1991 construction permit application.			5.13		
C-92-140 DNO storage tanks 138, 139	Operation commencement date not available; construction permit issued 11/24/1992. VOC emissions increase			7.22		

Table 5. Netting Analyses

project	Comments	emissions changes (tons/yr)				
		SO2	NOx	VOC	CO	PM10
	based on 8/5/1992 construction permit application, assuming 6 million gallons per year for each tank, and including fugitives. No credit taken for shutdown of Tank 187.					
C-92-142 Dubbs off gas compressor spare	Based on revised valve count (12/10/1992 letter to DAQ, requesting revocation of construction permit; request was denied).			1.44		
C-93-040 contractor fuel tanks	Commence operation date 5/20/1993 (based on 5/21/1993 letter to DAQ). Emissions increases based on 3/16/1993 construction permit application.			0.21		
C-93-116 SDA Unit Restart	Commenced operation 9/3/1994 through 9/16/1994 (for individual emission units). Emissions increases based on 9/13/1993 letter to DAQ requesting revisions to construction permit.	11.73	39.99	39.64	15.26	2.18
C-93-182 Refinery vehicle gasoline tank	Based on construction permit application.			0.47		
C-94-014 Solvent loading thermal oxidizer	Commenced operation 7/12/1996 (based on 7/18/1996 letter to DAQ). VOC emissions change based on 7/27/1993 construction permit application. Other increases based on 11 MMBtu/hr heat input and AP-42 Section 1.4.	0.03	4.82	-16.47	4.05	0.37
S-94-181 replace 10 tanks	Project scope involved replacing 10 existing tanks with 10 tanks having the same ID numbers. (Necessary to accommodate fire code.) VOC emissions increase represents PTE-to-actual, based on 9/13/1994 permit application.			9.42		
S-95-006 Tank 734 to gasoline service	Commence operation 7/1/1996 (based on 7/2/1996 letter to DAQ). Emissions increase based on 6/19/1995 construction permit application, reflects post-change PTE and pre-change actual (in diesel service).					
S-95-037 Lube vacuum tail gas recovery system	Commence operation 12/28/1995 (based on 1/3/1996 letter to DAQ). VOC emissions increase based on 9/29/1994 construction permit application.			4.62		

Table 5. Netting Analyses

project	Comments	emissions changes (tons/yr)				
		SO2	NOx	VOC	CO	PM10
S-95-120 Tank 64 replacement	Commence operation 9/26/1995 (based on 10/11/1995 letter to DAQ). Emissions increase based on 4/13/1995 construction permit application, reflects PTE of new tank and actual emissions of old tank.			-0.21		
S-95-152 CCR chlorination agent change	No change in emission rate for any PSD/NSR-regulated pollutant. Phase-out of carbon tetrachloride mandated by Title VI of Clean Air Act. Does not change "normal operation" of the unit.					
S-95-145 Replace #4 vacuum heaters	Commence operation date not available; construction permit issued 7/31/1995. Emissions changes reflect installation of heater 2-26-B-2 and shutdown of 2-1-B-1 and 2-23-B-1, based on 6/5/1995 construction permit application.	10.61	-3.6	-5.0	15.78	1.97
S-95-172 Dubbs area vacuum tail gas recovery	6/19/1995 construction permit application includes no emission estimates other than VOC from new piping.			4.62		
S-96-091 #5 crude charge heater duty increase	Based on 1/26/1996 construction permit application.		69.00	0.34	9.75	21.94
S-95-213 New north area CCR heaters	Construction permit application 2/16/1993 for increasing fired duties		124.00			
S-96-016 propylene/propane bullets relocation	VOC emissions increased based on 12/14/1995 construction permit application.			6.60		
S-96-018 Tank 355	Commenced operation 11/8/1996. Emissions increase based on 12/15/1995 construction permit application, reflects prereconstruction actual emissions and post-reconstruction PTE.			-3.97		
S-96-207 Cumene unit expansion	(see 2/13/1996 permit application)	9.00	39.9	32.00	11.00	
S-96-242 Toluene tanks change in service	Project scope involved replacing 4 existing tanks (5, 6, 112, 113) with 4 new tanks (26, 195, 196, 197). Emissions increase represents PTE-to-actual, based on permit			3.86		

Table 5. Netting Analyses

project	Comments	emissions changes (tons/yr)				
		SO2	NOx	VOC	CO	PM10
	application.					
S-96-251 Add loading arms at Viney Branch	Emissions increases based on permit application.			17.43		
Note: assume PSD contemporaneous period begins 4/1/1997; projects above here are not counted for PSD						
S-97-012 Tank 902 Isomerate charge	Emissions increases based on 11/4/1996 permit application. Commenced operation 3/11/1998.			5.43		
S-98-057 Ethanol storage tank at Viney Branch	Emissions increases based on permit application.			2.56		
S-98-088 Hydrogen coalescers	VOC emissions increases from new piping components, based on 8/31/1998 construction permit application.			7.13		
S-98-089 Change chlorinating agent at Isom Unit	No change in emission rate for any PSD/NSR-regulated pollutant. Phase-out of carbon tetrachloride mandated by Title VI of Clean Air Act. Does not change "normal operation" of the unit.			0.00		
S-99-052 HF Alky flare drum relocation	VOC emissions increase stated in 5/12/1999 construction permit application. No credit taken for any decrease resulting from removal of components associated with existing underground drum.			3.15		
S-00-007 Tank 733 modification	VOC emissions increase based upon 10/19/1999 permit application. Commence operation date not known.			3.76		
S-00-011 RCC regenerator	Commenced operation 3/1/2000 (based on 3/3/2000 letter to DAQ). RCC CO boiler increases calculated as difference between 1997-1999 actual and 1999-2001 actual. Increases reflect 11/2001 revision to permit.	0.89	8.34		22.24	
WO9902020 #2 Refinery railcar loading rack				-0.80		
N/A Wastewater plant modifications				4.64		
N/A LEP gas compressor				4.99		

Table 5. Netting Analyses

project	Comments	emissions changes (tons/yr)				
		SO2	NOx	VOC	CO	PM10
WO9902871 Asphalt cooling NTE				2.13		
N/AIso-octene unit				5.38		
WO990761 Tank 144 change of service				1.18		
WO990755 New fuel gas vent drum 2-66-F-13				1.20		
WO9900756 Piping from 894 tank to #3 crude unit				1.87		
WO990842KY Barge loading line relief				1.60		
WO990765 Remove Tank 65 IFR				10.16		
WO990856 AC-5 closed-loop sampler for lube vac unit				0.03		
WO990770 Tank 122 - add 3 valves				0.05		
WO000373 Pitch unit piping installations				0.52		
WO000162 Alky depropanizer to Alky regen				0.11		
WO000395 2-30-F-11 depropanizer relief valve				0.21		
WO000333 Spillback line from 701/702 tank pumps				0.08		
WO R09-1191 New bleeder at 110-E-25				0.02		
WO990015 South end light oil tank farm - underground lines				0.68		

Table 5. Netting Analyses

project	Comments	emissions changes (tons/yr)				
		SO2	NOx	VOC	CO	PM10
WO003785 Route depropanizer sidedraw to D12				0.08		
WO000028 New tank 105 in slurry/fuel oil service				0.31		
WO000081 MEK filters				0.37		
WO000457High sulfur isobutane at sat gas plant				0.06		
WO000473 Closed loop sampler at #1 SRU				0.12		
WO000470 Closed loop sampler at Pchem fuel gas				0.18		
WO000469 Closed loop sampler at MEK unit				0.05		
WO000467 Closed loop sampler at south area fuel gas				0.11		
WO000471 Closed loop sampler at HP CCR				0.12		
WO000472 Closed loop sampler at VGO				0.09		
WO000468 Closed loop sampler at RCC gas con reflux				0.09		
WO000117 Closed loop sampler at RCC gas con fuel				0.08		
WO000459 Drain lines on KOH heater				0.12		
WO000081 Pitch unit pump seals				0.34		
n/a Add 4 diesel loading arms				0.28		
WO9902798 Cumene unit relief system capital				0.23		

Table 5. Netting Analyses

project	Comments	emissions changes (tons/yr)				
		SO2	NOx	VOC	CO	PM10
WO359133 Cumene unit relief system expense				0.08		
WO1049133 VGO relief system expense				0.08		
WO289133 ADS/CTLO unit relief system expense				0.23		
WO9902631 Cooled sat gas pumparound system				0.51		
WO9902751 Add flow meter to 2-106-B-301 side nozzle				0.08		
WO000497Relocation of lube 41-tc-44				0.03		
WO980503 Block and bleed valves in lube vac tower				0.12		
WO9902961 Flush line to caustic precipitator				0.02		
N/A implement 40 CFR 63 subpart H LDAR				-256.08		
TOTAL		**-3,604.82**	**-953.06**	**-64.32**	**-1.06**	**-32.56**

III. REGULATORY APPLICABILITY AND FEDERALLY ENFORCEABLE CONDITIONS AND LIMITATIONS

A. PSD

The Kentucky PSD program, 401 KAR 51:017, applies to construction of a major source or major modification in an area that is not designated nonattainment for the pollutant in question. This program meets the federal PSD program requirements set forth at 40 CFR 51.166, as required by part c, Title I of the Clean Air Act. The area in which the Catlettsburg refinery is located, in Boyd County, is either undesignated or is designated attainment for all pollutants other than SO_2.

Applicability of the PSD regulations is not triggered for the Refinery Modernization Project because no significant net emissions increase will result. The net emissions increases for all PSD-regulated pollutants, and the corresponding "significant" levels, are shown in Table 6. The emissions increase calculations include emissions from new and modified emissions units as well as other affected emissions units upstream and downstream of the new and modified equipment. Consistent with current U.S. EPA policy, emissions increases for all modified and debottlenecked emissions units are calculated using a past-actual-to-future-potential methodology. For PM/PM10, NOX, CO, and VOC emissions, netting analyses were performed, including all contemporaneous emissions increases and decreases. For all pollutants, the net emissions increases are less than significant (in fact, for VOC, SO_2, and NOX, the project will result in significant decreases).

B. Nonattainment NSR

The Kentucky nonattainment NSR program, 401 KAR 51:052, applies to construction of a major source or major modification in an area that is designated nonattainment for the pollutant in question. This program meets the federal nonattainment NSR program requirements set forth at 40 CFR 51.165, as required by part d, Title I of the Clean Air Act. The area in which the Catlettsburg refinery is located, in Boyd County, is designated nonattainment for SO_2.

Applicability of the nonattainment NSR regulations is not triggered for the Refinery Modernization Project because no significant net emissions increase will result. The net emissions increase and the corresponding "significant" level for SO_2 are shown in Table 6.

TABLE 6. SUMMARY OF PSD/NSR APPLICABILITY, VF-02-001 (Revision 1)

Pollutant	Net Emissions Increase (tons/yr)	Significant Thresholds (tons/yr)	PSD or NSR?	PSD/NSR apply?
PM	-33	25	PSD	No
PM-10	-33	15	PSD	No
SO_2	-3,605	40	NSR	No
NO_X	-953	40	PSD	No
VOC	-65	40	PSD	No
CO	-1	100	PSD	No

C. Marathon Ashland Petroleum / U.S. EPA Global NSR Settlement

Catlettsburg Refining and its parent company, Marathon Ashland Petroleum, entered into a consent decree with U.S. EPA in May 2001. This consent decree requires the implementation of certain environmental measures at the Catlettsburg refinery. In addition, the consent decree discourages Catlettsburg Refining from relying on certain of the emission reductions, required under the consent decree, in PSD or nonattainment NSR netting analyses.

Catlettsburg Refining has represented to the Division that the netting analyses described herein do not rely on emission reductions, the use of which is discouraged under the consent decree. Specifically, the following emission reductions are not relied upon in the PSD and nonattainment NSR netting analyses for the Refinery Modernization Project:

- The SO_2 emission reduction of 195.5 tons per year from the #2 Crude Charge Heater (Unit No. 1-2-B-3). This reduction will result from elimination of oil firing, which is required under the consent decree.

- The NO_X emission reductions of 276.2 tons per year from the #3 Crude Charge Heaters (Unit Nos. 2-23-B-3 and 2-23-B-4) and 97.6 tons per year from the HPVGO Hydrotreater Charge Heaters (Unit Nos. 2-104-B-1 and 2-104-B-2). These reductions will result from retrofitting with low-NO_X burners, which is required under the consent decree.

- A portion of the SO_2 and NO_X emission reductions from the existing FCC Unit (No. 2-1) and CO Boiler (Unit No. 2-601-B-9). The permit requires shutdown of these units, which will result in emission decreases of 3,193.5 tons SO_2 per year and 387.0 tons NO_X per year. The consent decree does not require shutdown, but would require implementation of emission reduction measures. Under the consent decree, the maximum allowable emissions from the existing FCC Unit (No. 2-1) and CO Boiler (Unit No. 2-601-B-9) would be 137.6 tons SO_2 per year and 177.8 tons NO_X per year. Thus, emission reductions of 3,055.4 tons SO_2 per year and 209.2 tons NO_X per year are discouraged from being relied upon under the consent decree.

- A portion of the SO_2 emission reduction from the existing RCC Unit (No. 2-109) and Heat Recovery Units (Nos. 2-116-B-1 and 2-116-B-2). The permit limits the SO_2 emissions from these units to 256.0 tons SO_2 per year. As compared to past actual emissions of 1,049.0 tons SO_2 per year, this limit will require an emission decrease of at least 793.0 tons SO_2 per year. The consent decree would require implementation of emission reduction measures that would result in allowable SO_2 emissions of 681.0 tons per year. Thus, emission reductions of 368.0 tons SO_2 per year are required by the consent decree and are discouraged from being relied upon under the consent decree.

- The NO_X emission reduction of 261.0 tons per year from the existing RCC Unit (No. 2-109) and Heat Recovery Units (Nos. 2-116-B-1 and 2-116-B-2). This reduction will result from implementation of several measures that are required under the consent decree.

- The total SO_2 emission reduction that is required by this permit and discouraged from being relied upon under the consent decree, as described above, is 3,618.9 tons per year. The net SO_2 emissions decrease shown in Table 5 is 3,599.6 tons per year. Thus, without considering the emission reductions that are required by the consent decree, the net SO_2 emissions increase for the Refinery Modernization Project would be 19.3 tons per year.

- The total NO_X emission reduction that is required by this permit and discouraged from being relied upon under the consent decree, as described above, is 844.0 tons per year. The net NO_X emissions decrease shown in Table 5 is 945.3 tons per year. Thus, without considering the emission reductions that are required by the consent decree, the net NO_X emissions decrease for the Refinery Modernization Project would be 101.3 tons per year.

D. NSPS

Federal New Source Performance Standards (NSPS) are required under section 111 of the federal Clean Air Act and are codified at 40 CFR part 60. Several NSPS regulations are potentially applicable to emissions units that are affected by the Catlettsburg Refinery Modernization Project.

The NSPS for Petroleum Refineries, 40 CFR 60 subpart J, is applicable to the new FCC Unit (ID No. 2-109) and to several fuel gas combustion devices at the Catlettsburg refinery. Where applicable, this regulation is noted on the DEP7007V permit application form included in Appendix A.

NSPS subpart J is not applicable to the Hydrogen Generation Unit Reformer Heater (ID Nos. 2-122-B-1) because this unit combusts only natural gas.

NSPS subpart J is applicable to the Sulfur Recovery Plant (ID Nos. 2-106, 2-107, 2-118, 2-119, and 2-120). This regulation limits SO_2 emissions to 250 ppmv on a dry, oxygen-free basis.

The NSPS for Volatile Organic Liquid Storage Vessels, 40 CFR 60 subpart Kb, is applicable to the new Tank 920 and to several existing tanks, as noted in the Kentucky DAQ air quality permit application form DEP7007V. It is worth noting that several other tanks, including Tank Nos. 152, 701, 702, 783, 821, and 845, are not subject to any NSPS regulation because these tanks have not been constructed, reconstructed, or modified after June 11, 1973. The Refinery Modernization project will not involve any modifications to these tanks, although the tanks may undergo minor changes such as being insulated or having new nozzles installed.

The NSPS for Equipment Leaks of VOC in Petroleum Refineries, 40 CFR 60 subpart GGG, is applicable to several process units at the Catlettsburg refinery. Three new compressors in VOC service are being installed as part of the Refinery Modernization Project, each of which is a separate affected facility for NSPS applicability purposes. Where applicable, NSPS subpart GGG is noted on the DEP7007V permit application form included in Appendix A. It is worth noting that NSPS subpart GGG is not applicable to the Hydrogen Generation Unit (ID No. 2-122) because this unit does not include any equipment in VOC service, as that term is defined at 40 CFR 60.481.

The NSPS for VOC Emissions from Petroleum Refinery Wastewater Systems, 40 CFR 60 subpart QQQ, will apply to the new drain system associated with the Hydrogen Generation Unit (ID No. 2-122). This drain system will comply with the provisions of 40 CFR 60.692-2. Wastewater from this drain system will be conveyed to the refinery's existing NESHAP-compliant wastewater system.

NSPS subpart Dc is applicable to the HF Alky Unit Hot Oil Heater (ID No. 2-36-B-2). The SO_2 and PM emission standards under subpart Dc are not applicable because this unit will not burn coal, oil, or wood.

The NSPS for Volatile Organic Liquid Storage Vessels, 40 CFR 60 subpart Kb, is applicable to the new Tanks 910, 911, 912, 913, and 920.

E. PRE-1990 NESHAP

National Emission Standards for Hazardous Air Pollutants (NESHAP) promulgated prior to the Clean Air Act Amendments of 1990 were established as risk-based standards (post-1990 NESHAP are technology-based standards and are discussed in Section 3.4 of this permit application).

The NESHAP for Benzene Waste Operations, 40 CFR 61 subpart FF, is applicable to all petroleum refineries, including the Catlettsburg refinery. The Refinery Modernization Project will not impact the manner or extent to which this regulation applies to the Catlettsburg refinery. The Catlettsburg refinery will continue to comply with the standards under 40 CFR 61.342(e). No new benzene-containing waste streams requiring control under 40 CFR 61.342(c)(1) will be generated by the Refinery Modernization Project.

F. MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

NESHAP standards promulgated subsequent to the Clean Air Act Amendments of 1990, as required by § 112(d) of the Act, are generally referred to as Maximum Achievable Control Technology (MACT) standards. These standards apply to major sources of HAP, including the Catlettsburg refinery.

The Catlettsburg refinery is subject to the MACT standard for Petroleum Refineries, 40 CFR 63 subpart CC. This regulation includes emission standards for miscellaneous process vents, storage vessels, wastewater, equipment leaks, gasoline loading racks, and marine vessel tank loading operations. The Catlettsburg refinery is an existing source and is subject to the emission standards for existing sources in each of these emissions unit subcategories. The Refinery Modernization project will have little impact on the manner and extent to which subpart CC is applicable. In particular, it is worth noting that all process units at the Catlettsburg refinery will continue to be regulated, collectively, as an existing affected source.

The only new process unit, the Hydrogen Generation Unit (ID No. 2-122), will not have the potential to emit 10 tons per year of any HAP or 25 tons per year of HAPs in total. Thus, under §63.640(i), the Hydrogen Generation Unit is treated as a part of the existing affected source. The Reformer Vent is specifically excluded from the definition of "miscellaneous process vent" at §63.641 and, thus, is exempt from the MACT emission standards.

In addition, the modifications being made to existing process units will not constitute reconstruction (which would require the addition of components with a fixed capital cost exceeding 50 percent of the fixed capital cost that would be required to construct a comparable new refinery). Thus, under §63.640(j), these modified units will continue to be regulated as an existing affected source.

Other MACT standards may impact the refinery in the future. In particular, the standard for catalytic cracking units, catalytic reforming units, and sulfur plants is likely to be promulgated in 2001 and to be codified at 40 CFR 63 subpart UUU. The impacts of any future MACT standards, if any, will be addressed once the standards become effective.

The federal *Case-by-Case MACT* rule, codified at 40 CFR 63.40 through 63.44 and incorporated by reference at 401 KAR 63:105, implements § 112(g) of the Clean Air Act, as amended. This rule applies to new or reconstructed major sources of HAP that are not covered by a source category MACT standard. The Refinery Modernization Project will not involve any such construction or reconstruction.

G. KENTUCKY NEW SOURCE STANDARDS

Several of the emission standards set forth at 401 KAR Chapter 59 are applicable to the Catlettsburg refinery and to the Refinery Modernization Project. These include the following:

401 KAR 59:015, “New indirect heat exchangers,” is applicable to the new Reformer Heaters (ID Nos. 2-122-B-1) and several existing heaters, as noted in the Kentucky DAQ air quality permit application form DEP7007V included in Appendix A. It is worth noting that this regulation is not applicable to the No. 3 Crude Unit Charge Heaters (ID Nos. 2-23-B-3 and 2-23-B-4) because these heaters have not been constructed or modified after August 17, 1971. The Refinery Modernization Project will not involve any modification (as that term is defined at 401 KAR 59:001) to these heaters.

401 KAR 59:046, “Selected new petroleum refining processes and equipment,” is applicable to process unit turnarounds and to vacuum-producing systems throughout the refinery.

401 KAR 59:050, “New storage vessels for petroleum liquids,” is applicable to the new Tank 920 and to several existing tanks, as noted in the Kentucky DAQ air quality permit application form DEP7007V. It is worth noting that several other tanks, including Tank Nos. 152, 701, 702, and 783, are not subject to this regulation because these tanks have not been constructed or modified after April 9, 1972. The Refinery Modernization Project will not involve any modification to these or any other storage vessels.

401 KAR 59:105, “New Process Gas Streams,” includes emission limitations for CO, H2S, and SO_2 for process gas streams not otherwise covered by regulations under Chapter 59. The CO and SO_2 regulations are not applicable to any gas streams affected by the Refinery Modernization Project. The H2S limitation is applicable to several process gas streams, as noted in the Kentucky DAQ air quality permit application form DEP7007V. Compliance with the applicable H2S emission limitation is achieved by routing the process gas streams to sulfur recovery plants and combustion devices.

CREDIBLE EVIDENCE:

This permit contains provisions that require that specific test methods, monitoring or recordkeeping be used as a demonstration of compliance with permit limits. On February 24, 1997, the U.S. EPA promulgated revisions to the following federal regulations: 40 CFR Part 51, Sec. 51.212; 40 CFR Part 52, Sec. 52.12; 40 CFR Part 52, Sec. 52.30; 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12, that allow the use of credible evidence to establish compliance with applicable requirements. At the issuance of this permit, Kentucky has not incorporated these provisions in its air quality regulations.